UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
And Nora Mead Brownell.

San Diego Gas & Electric Company,
Complainant,

v. Docket No. EL00-95-056

Sellers of Energy and Ancillary Service Into
Markets Operated by the California
Independent System Operator Corporation
and the California Power Exchange Corporation,
Respondents

Investigation of Practices of the California Docket No. EL00-98-049
Independent System Operator and the
California Power Exchange

ORDER ON REHEARING AND CLARIFICATION

(Issued May 15, 2002)

In this order, the Commission acts on petitions for rehearing and clarification of a December 19 order accepting in part and rejecting in part the California Independent System Operator's (ISO's) January 2, May 11, and July 10, 2001 compliance filings.[1] The Commission denies rehearing of the December 19 Compliance Order. While the order also clarifies several minor issues, the general mitigation scheme set forth in previous orders remains unchanged by this order. This order reflects the appropriate implementation of our previous findings regarding the California markets and will promote a more efficient operation of the wholesale electricity markets in California to the benefit of all customers.

[1]San Diego Gas & Electric Co., et al., 97 FERC ¶ 61,293 (2001) (December 19 Compliance Order).

Background

Over an eight-month period, ISO submitted four compliance filings and proposed Tariff revisions in response to Commission orders addressing the high price of electricity in the markets operated by ISO and the California Power Exchange (PX). In the first such order, issued on December 15, 2000, the Commission established certain remedies to alleviate the extremely high electricity prices being borne by Californians.[2] In response, ISO submitted a compliance filing on January 2, 2001 that implemented the Commission's directives.

On May 11, 2001, ISO made another compliance filing and proposed Tariff revisions in response to the Commission's April 26, 2001 order that established a prospective mitigation and monitoring plan for wholesale markets operated by the ISO.[3] The May 11 filing, among other things, provided for the ISO's implementation of the Commission's directives regarding a requirement for all sellers that own or control generation in California to offer all of their available power in the ISO's real-time energy market and a price mitigation mechanism for the ISO's real-time energy market during system emergencies.

On rehearing of the April 26 order, the Commission issued an order on June 19, 2001 that modified and expanded the mitigation plan and extended price mitigation to wholesale spot markets thought the Western Systems Coordinating Council (WSCC). On July 10, 2001, ISO submitted a new compliance filing in response to the June 19 order on rehearing. On July 30, 2001, ISO filed revised Tariff sheets as an amendment to its May 11 and July 10, 2001 Compliance Filings.

The December 19 Compliance Order addressed ISO's compliance filings and proposed Tariff revisions filed on January 2, May 11, July 10 and July 30, 2001, and

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[2] San Diego Gas & Electric Co., et al., 93 FERC ¶ 61,294 (2000), on reh'g, 97 FERC ¶ 61,275 (2001).

[3] San Diego Gas & Electric Co., et al., 95 FERC ¶ 61,115 (2001) (April 26 order), order on reh'g, 95 FERC ¶ 61,418 (2001) (June 19 order), on reh'g, 97 FERC ¶ 61,275 (2001), reh'g pending.

directed ISO to make an additional filing.[4] Further, the Commission issued two other orders on December 19, 2001 addressing issues in the Western markets.[5]

Discussion

A. Procedural Matters

The parties listed in the Appendix filed timely motions for rehearing and/or clarification.[6]

B. Rehearing of Issues to December 19 Compliance Filing

1. Definition of System Emergency and Effective Date

In our December 19 Compliance order, we required the ISO to modify its Tariff to recalculate the mitigated Market Clearing Price (MCP) when reserves in California fall below 7 percent.[7] We determined that establishing a specific reserve level for recalculating the mitigated prices was appropriate and reasonable because it enhances market certainty during the mitigated period. Accordingly, we directed the ISO to amend its Tariff to reflect a definition of a Stage 1 system emergency to occur when reserves fall below 7 percent. This finding was made effective May 29, 2001, the effective date of our mitigation plan as established in our April 26 order.

On rehearing, the ISO argues that the Commission's requirement to make recalculation of the mitigated prices triggered when reserves in California fall below 7 percent will result in the use of a reserve margin that does not comport with the Western Systems Coordinating Council (WSCC) reserve requirements. The ISO states that under

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[4]The December 19 Compliance Order, 97 FERC ¶ 61,293 at 62,360-61, describes the relevant Commission orders and ISO compliance filings in greater detail.

[5]San Diego Gas & Electric Co., et al., 97 FERC ¶ 61,275 (2001) (order on rehearing); and San Diego Gas & Electric Co., et al., 97 FERC ¶ 61,294 (2001) (order temporarily modifying the west-wide price mitigation methodology or "Winter Price Order").

[6]The Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California filed a request for clarification, and subsequently withdrew their filing.

[7]December 19 Compliance Order at 62,364.

the WSCC reserve requirements, the average monthly operating reserve obligations for the year 2001 was not 7 percent, but approximately 6.2 percent. Therefore, the ISO requests that the Commission modify its requirement of a 7 percent reserve requirement trigger for recalculation of the mitigated market clearing price to 6.2 percent. If not revised, the ISO states that in order to avoid the 7 percent trigger mechanism, it will incur additional costs for the procurement of unnecessary and excessive operating reserves above the WSCC requirement.

SoCal Edison argues that since the trigger for recalculating the mitigated market clearing price will be based on when reserves in California fall below 7 percent, the Commission should order the ISO to make available on its internet website both the amount of reserves available and the standards used to determine the amount of reserves. This requirement would provide market participants with greater transparency regarding the potential triggering of a new mitigated market clearing price.

Reliant argues that the retroactive implementation of the 7 percent triggering mechanism back to May 29, 2001 to recalculate the mitigated price is problematic and fundamentally unfair to market participants. Reliant contends that the retroactive application of this operating reserve level will cause the ISO to reset mitigated prices and, thus, require further justification of bids above the mitigated price. Reliant also argues that sellers do not have the opportunity to modify their behavior to fit the retroactive requirement because the time frame to submit cost justification has expired. As a result, Reliant requests that the Commission grant rehearing for the limited purpose of revising the effective date to allow the change and implementation to be prospective.

Dynegy also requests that the Commission grant clarification, or in the alternative rehearing, to make the revised triggering mechanism for determining non-reserve deficiency MCP effective as of May 1, 2002, the day after the temporary west-wide price mitigation methodology expires.[8] Dynegy claims that the Commission failed to consider the impact of setting a retroactive effective date on prospective mitigation measures. For example, Dynegy notes that reserves fell below 7 percent on July 2 and July 3, 2001, but because the ISO never declared a System Emergency, prices were not reset. Dynegy further states that if the Commission's 7 percent reserve triggering mechanism is applied retroactively, the non-reserve deficiency price would be capped at $44/MWh, and not the $92/MWh mitigated price established under the west-wide mitigation order. Dynegy argues that to significantly reduce the prevailing mitigated price without finding that rates were unjust and unreasonable is extremely harsh and would produce significant refund

[8]Winter Price Order, 97 FERC ¶ 61,294 (2001).

obligations to sellers that complied with the Commission's prospective mitigation measures.

Commission Response

We deny the ISO's request for rehearing that the Commission find that the ISO's 6.2 percent actual reserve requirement trigger the recalculation of the mitigated market clearing price. To modify the triggering mechanism to reflect actual WSCC reserves of 6.2 percent for the year 2001 would not rectify any claimed unjust or unreasonable result but rather simply, at best, conform the triggering mechanism to be precisely aligned with WSCC reserve requirements. However, this would place form over substance. We believe that the 7 percent reserve amount as the triggering mechanism for recalculation of the mitigated market clearing price is appropriate because its continued use is consistent with our intent to provide market participants with as much certainty in the California markets as possible during the period when our mitigation plan is in effect.[9]

We will grant Dynegy and Reliant's requested rehearing and clarify that the effective date of the 7 percent triggering mechanism for the recalculation of the mitigated market clearing price is December 19, 2001 rather than May 29, 2001. We note that the ISO, in its July 10, 2001 compliance filing, stated that the Commission's June 19 Order incorrectly referred to Stage 1 System Emergencies as being synonymous with "reserve deficiency hours", i.e., when reserves fall below 7 percent. The ISO further stated that its emergency procedures provide for flexibility in declaring a System Emergency, to permit the ISO to take into account changing forecasts and the dynamic behavior of both supply and demand. The ISO concluded that it believed linking the price mitigation provided in the June 19 Order to a fixed threshold of system reserves was inappropriate and it proposed to implement the price mitigation plan based upon the clearing prices that occur during ISO-declared System Emergencies. Thus, for the period from May 29, 2001 through December 18, 2001,[10] the ISO implemented the triggering mechanism not on the basis of reserves in California falling below 7 percent but rather when an ISO-declared System Emergency occurred.

We find that until December 19, 2001, the ISO incorrectly implemented the triggering mechanism at its own discretion rather than when reserves in California fell

[9] April 26 Order at 62,364.

[10] The Commission presumes that the ISO implemented our 7 percent triggering mechanism on December 19, 2001 based on findings in the December 19 Compliance Order.

below 7 percent. Retroactively implementing the automatic 7 percent triggering mechanism to May 29, 2001 would require the ISO to reset mitigated prices. However, all market participants, including Dynegy and Reliant, had to operate under the ISO's then-current terms and conditions regarding implementation of the Commission's mitigation plan. Therefore, a retroactive effective date for a triggering mechanism of mitigated market prices that would change the ISO mitigated prices could not result in market behavioral changes. As such, the 7 percent reserve criteria for the triggering of a recalculation of the mitigated market clearing price should be effective December 19, 2001.

Because the 7 percent triggering mechanism is effective as of December 19, 2001, there is no need to make it effective May 1, 2002. Accordingly, Dynegy's request that the triggering mechanism for determining the mitigated prices be effective May 1, 2002, is denied. However, we also find the ISO's non-compliance with previous Commission findings regarding market terms and conditions inappropriate, and caution the ISO and other similarly-situated entities that future non-compliance with Commission findings that will have immediate market impacts will be rejected.

We will grant SoCal Edison's request for rehearing with respect to greater transparency of the reserves available to the ISO. We find it reasonable for the ISO to publish the operating reserve levels for the relevant market because it provides among other things market certainty and greater transparency of the operating reserves in California and West-wide. Therefore, we will require that the ISO post the operating reserve levels on their internet website, as proposed by SoCal Edison.

2. <u>Must-Offer Obligation</u>

a. <u>Exemption Procedure</u>

Reliant argues in its rehearing request that the Commission's acceptance of the ISO's proposed exemption procedures violated the Commission's filing requirements under Section 205 of the Federal Power Act (FPA) and also denied interested parties from commenting on those procedures. In support, Reliant notes that the Commission acknowledged in its December 19 Compliance Order that the exemption procedures "affect the rates and charges for wholesale energy in California," and subsequently required the ISO to file tariff sheets that provide enough specificity to ensure the procedures are nondiscriminatory and transparent to market participants. Accordingly, Reliant contends that the Commission should correct this error on rehearing by suspending implementation of the exemption procedures until the ISO files these procedures with sufficient specificity, so as to allow parties to comment on them. As a collateral issue, Reliant argues on rehearing that the Commission failed to address the previous concerns it raised in its prior protest regarding implementation of the ISO's proposed exemption procedures.

Commission Response

The December 19 Compliance Order did not accept for filing the ISO's exemption procedures but, rather, only found the concept of exemptions reasonable. Accordingly, the Commission directed the ISO to make a compliance filing to incorporate into its tariff these provisions, effective July 20, 2001. The ISO has made the requisite compliance filing and Reliant has, along with other interested parties, commented on the ISO's tariff sheets that will implement the exemption procedures. Thus, Reliant's concerns regarding its ability to comment on these procedures have been satisfied. Additionally, we find moot Reliant's rehearing concerning our purported failure to address Reliant's prior arguments concerning these procedures since it now had the opportunity to raise all relevant arguments to these exemption procedures. The Commission will address the exemption procedures in a separate compliance order being issued concurrently with this order.

Reliant's arguments regarding the application of section 205 filing requirements to the ISO's exemption procedures is only relevant as it relates to an assignment of a July 20, 2001 effective date to the ISO's exemption procedures. However, neither Reliant nor any other intervening party has raised on rehearing any arguments that the assignment of the July 20, 2001 effective date has adversely affected them. Therefore, we deny Reliant's request for rehearing that the ISO should have filed the exemption procedures under section 205 of the FPA rather than as a market notice.

b. Implementation of the Must Offer Obligation

Duke seeks rehearing that the must-offer obligation should not apply to generating units that are not scheduled to run and have not received dispatch instructions from the ISO.[11] Duke claims that by requiring a generator to run continuously under the must offer requirement, when it would be otherwise shutdown, imposes costs beyond the actual running costs. For example, Duke states that a generator in standby mode under the must offer obligation will incur additional operation and maintenance costs, deferred minor maintenance, wear and tear, and greater risk of forced outages. Duke argues that under circumstances where a generator is not scheduled or dispatched by the ISO, the Commission should require the ISO to demonstrate that its existing reserve requirements

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[11] December 19 Compliance Order, 97 FERC at 62,363.

are inadequate. The Commission should grant rehearing of the must-offer obligation to allow generators to shutdown their units, without being subject to the must-offer requirement, when they are neither scheduled to run nor dispatched by the ISO.

In the alternative, Duke contends that the Commission should modify the December 19 Compliance Order to allow generators to be fully compensated for capacity reserve service under the must-offer obligation. Duke claims that the must-offer obligation is, confiscatory because generators are not being fully compensated for must-offer service, and also discriminatory since must offer generators will be compensated less favorably than reliability must-run generators. Duke states that when the ISO denies a generator the right to shut down, the generator is compelled to provide capacity service and also energy at minimum load. Duke argues that load serving entities should be required to pay for the value of energy and reserve capacity made available because load serving entities are the recipients that benefit from what Duke characterizes as the "Must-Run" requirement. Duke contends that denying a generator the opportunity to recover its total costs, or earn a reasonable rate of return on the use of its investment is unjust and unreasonable.

Commission Response

We are not persuaded by Duke's argument that the must-offer obligation should not apply to generating units that are not scheduled to run and have not received dispatched instructions from the ISO. As we explained in the June 19 Order, we instituted the must-offer obligation to prevent withholding and thereby to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. [12] We reiterate that generators are provided the opportunity to request an exemption of the must-offer obligation when they believe circumstances would warrant such exemption. Therefore, we continue to believe that the requirement to make all generation, with the exception of hydroelectric generation, available to operate at minimum load unless the ISO has otherwise granted an exemption is reasonable because it provides the assurance of a reliable system. The ISO's exemption procedures will be subject to Commission review and, thus, the ISO will bear the burden of demonstrating its decisions regarding exemption requests.

With respect to Dukes request that, in the alternative, the Commission allow generators to be fully compensated for capacity reserve service under the must-offer obligation, we find that if generators are dispatched under the must offer obligation,

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[12] June 19 Order at 62,553.

unless it is the marginal costs unit that sets the market clearing price, the generator will receive some contribution to fixed costs. Therefore, Duke's request is denied. Generators who are dissatisfied with this finding regarding cost recovery of only minimum load status costs may propose cost-based rates for their generating units with cost support including a reasonable rate of return on investment that reflects the unique conditions in California.[13]

c. Other Must-Offer Obligation Issues

The ISO requests rehearing of the Commission's finding regarding the payment of minimum load costs. Specifically, the ISO argues that the payment of minimum load costs should include "net of market revenue" methodology in which the ISO only is required to reimburse the generator for minimum load operating costs not recovered through other sales for the period of time the generating unit is required to operate under must-offer obligation. In support, the ISO states that this netting approach produces a just and reasonable result balancing the generators need for appropriate cost recovery with consumer protections against unreasonable rates.

Reliant argues on rehearing that the must-offer obligation should be modified because it conflicts with the basic structure of the California market. Reliant argues that the must offer obligation should provide for a market-based approach to unit commitment to have sufficient units on-line to meet real-time markets. The procedures purportedly could be implemented using existing market mechanisms and platforms such as the Automated Power Exchange. Reliant believes that the market-based solutions to unit commitment is a better approach than the implementation of the must-offer obligation, and the Commission should modify its findings on rehearing to support what it argues is a more efficient, effective and market-based driven solution toward resolving the need for available capacity in California.

Commission Response

We will deny the ISO's request that minimum load costs be netted as proposed by the ISO. The revenues received by generators for sales in the imbalance energy market are, under market-based rate authority intended to compensate the generators for recovery of fixed costs. The ISO's netting approach would compromise this recovery. Our

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[13] June 19 Order at 62,564.

directive that provided for recovery of actual minimum load costs was not intended to compromise generators market-based rate revenues.

We note that Reliant's argument that the must-offer obligation should be modified to reflect a day-ahead unit commitment mechanism has been previously considered and rejected by the Commission.[14] We stated in the December 19 Winter Price Order that given the current stability in the California markets, we do not believe that more significant changes to the mitigation plan are needed at this time. We continue to believe that this is the case and, thus, we will deny Reliant's request for rehearing on this issue. However, we note that Reliant will have an opportunity to address the basic structure of the California market when the Commission considers the ISO's market design proposal to replace the current mitigation plan scheduled to terminate on September 30, 2002.[15]

3. Recovery of Emissions and Start-up Fuel Costs

a. Justification for Start-up Fuel Costs

Intervenors argue on rehearing that the Commission erred in its decision that the appropriate gas price used in determining start-up fuel costs incurred by generators under the must-offer obligation should be the average of the mid-point of the monthly bid-week gas prices because the method will not make generators whole for the actual costs they incur.[16] Specifically, Reliant contends that in order to make generators whole, the Commission should revise the formula to allow compensation based on an allegedly more realistic gas proxy for real-time transactions. In the alternative, Reliant suggests that the Commission base the gas proxy for real-time transactions on the daily spot index at the generator's delivery point.

Dynegy raises a similar concern with regard to the start-up fuel costs being based on the daily price average rather than monthly averages. It states that generators rely on spot purchases, not forward contracts for gas because generators cannot be expected to assume the risk of negotiating forward gas supply contracts simply to have gas to run at minimum load. Therefore, Dynegy contends that the Commission should apply the daily gas index price as an appropriate method for the recovery of start-up fuel costs.

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[14] Winter Price Order, 97 FERC ¶ 61,294 at 62,374.

[15] On May 1, 2002, the ISO submitted for filing its Comprehensive Market Design proposal in Docket No. ER02-1656-000.

[16] December 19 Compliance Order at 62,370.

Dynegy also requests on rehearing that the Commission allow for the recovery of legitimate costs associated with acquiring fuel to run at minimum load. Dynegy argues that there is no basis for the Commission to deny suppliers the opportunity to recover legitimate costs such as intrastate transportation costs, franchise fees, and certain taxes to comply with minimum load requirements under the must-offer obligation. By excluding these costs, Dynegy argues, generators will not recover their actual costs to run at minimum load. Therefore, Dynegy contends that the Commission should grant rehearing of the proposed method of calculating minimum load costs to include other legitimate costs associated with acquiring fuel to run at minimum load.

Intervenors also request that the Commission clarify whether the requirement that sellers receive their actual costs to run at minimum load includes the recovery of an O&M adder consistent with the $6/MWh O&M adder for mitigated prices. Reliant argues that the recovery of an O&M adder is a legitimate cost that generators incur because O&M costs are exceedingly high when operating at minimum load.

Commission Response

We deny intervenors' request that the gas proxy for start-up fuel cost reflect the daily index price. In the December 19 Compliance Order, we clarified that the appropriate gas price used in determining start-up fuel costs should be the same gas price used to determine proxy prices in the real-time market, i.e., the average of the mid-point of the monthly bid-week gas prices reported by Gas Daily for three spot markets reported for California. We reaffirm our finding in this order. The use of the average gas price in determining the start fuel costs is reasonable because generators generally pre-buy their monthly gas requirement rather than purchase gas on the daily spot market. In addition, we have found that the average monthly gas price has consistently been within a reasonable range of the daily spot market price. We reiterate that if sellers find that they are not fairly compensated for the start-up fuel costs, sellers may seek to recover costs above the average gas price by submitting their entire gas portfolio to the Commission and the ISO as justification. Accordingly, we find that sellers are granted the opportunity to be compensated for their gas costs.

Further, we deny Dynegy's request to include intrastate transportation costs, franchise fees, and certain taxes as legitimate costs under the minimum load status. Dynegy's support for recovery of these costs is predicated primarily on the fact that these costs are paid for by the generators on an energy basis ($/mmbtu). We find that while these costs may be paid for on an energy basis, they are, by definition, demand-related costs. As such, they are ineligible for cost recovery when the unit is in minimum load status. Again, if generators believe that this recovery mechanism is insufficient to cover their actual costs, they are free to file for costs-of-service rates covering all of their generating units for the duration of the mitigation plan.

Finally, with respect to the Intervenors' requested clarification on whether the minimum load costs will include an adder for O&M expenses, we clarify that the O&M expense is a legitimate cost that generators incur to operate at minimum load, and therefore should be included as a component of minimum load costs. In addition, our review of the ISO's compliance tariff sheets indicates that such expenses will be included.

b. Control Area Gross Load as a Billing Determinant for Allocating Emissions and Start-up Costs

A number of intervenors argue on rehearing of the December 19 Compliance Order [17] that the Commission erred and abused its discretion in accepting Control Area Gross Load as a billing determinant for allocating emissions and start-up costs because among other things: 1) the proposal is not consistent with the principle of cost causation; 2) the proposal violates the Commission's procedural rules of granting parties adequate notice of tariff amendments; 3) parties were given no opportunity to provide evidence to refute the proposal; and 4) the proposal has no methodology to estimate the appropriate Control Area Gross Load billing determinant for certain entities.[18]

Reliant argues on rehearing that the ISO should be required to modify the tariff to include a true-up mechanism to ensure actual emission and start-up costs are being fully recovered. Reliant claims that the Commission did not give due consideration to this issue in the December 19 orders. Reliant contends that a true-up mechanism is necessary because the ISO's proposal compensates generators for emissions and start-up fuel costs based on annually forecasted data. Reliant alleges that, to the extent there are forecasting errors, generators will have to wait for the ISO to adjust the collection rates to ensure the appropriate recovery of costs.

Dynegy argues that the Commission accepted the ISO's methodology to recover emissions and start-up costs without considering several fundamental arguments. First, Dynegy contends that the Commission should reject the provisions regarding emissions costs because the tariff does not: 1) adequately define how the estimates for emissions and financing costs, and total annual demands are to be derived; 2) adequately identify

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[17] Id.

[18] Rehearing requests by CAC/EPUC, SoCal Edison and Vernon.

the conditions that would make it necessary to adjust the emission costs rate; 3) limit the retroactive recovery of costs to errors, omission or miscalculations of the inputs; 4) disclose the type of disbursements the emissions trust account permits; and 5) include an emissions costs form even though the form is referenced.[19] Second, Dynegy argues that to the extent there are inadequate funds to satisfy emissions cost invoices, the ISO proposal to pay invoices on a pro rata basis with unpaid amounts being held over to the next month results in an unreasonable cost shift from the ISO to the generators.

Dynegy further contends that the Commission should reconsider the issue of apportioning emission costs between bilateral sales and the must-offer obligation. It argues that the generators must always split the additional emission costs incurred under the must-offer obligation because generators will enter into bilateral transactions using existing emission allowances, while subsequently being required by the ISO to operate above their emissions requirement. Dynegy claims that the splitting of emission allowances is unjustifiably difficult because generators will always face uncertain future emission costs. Therefore, the Commission should require the ISO to remove the pro rata allocation of emission costs as it relates to the execution of bilateral transactions prior to must-offer obligations.

Commission Response

We will deny intervenors request for rehearing that the Commission erred in its decision to accept Control Area Gross Load as a billing determinant. As we stated in the December 19 Compliance Order, the use of total gross load is the most appropriate method to assess emissions and start-up costs because all users of the transmission grid will be assigned these costs consistent with the ISO markets performing a reliability function.[20] We reaffirm our finding in this order. The Intervenors have raised no new arguments on rehearing that warrant a departure from our previous finding. With respect to the allegations that parties were denied the opportunity to provide evidence or proper notice, we note that our December 19 Compliance Order considered and ruled on protests and rehearing by various parties concerning the ISO's proposed procedure for recovery of these costs. Thus, we disagree that these parties have been unjustly denied an opportunity to comment on and present their position on the ISO's proposed methodology to recover these costs.

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[19] See ISO Tariff, Sections 2.5.23.3.6.3, 2.5.23.3.6.4, 2.5.23.3.6.5, 2.5.23.3.6.2 and 2.5.23.3.6.7, respectively.

[20] 97 FERC at 62,370.

We disagree with Dynegy's argument that the ISO Tariff provision for the recovery of emission costs is vague and discretionary. We believe that the tariff provisions are reasonable and adequately provide the ISO and market participants with the necessary guidelines to ensure the recovery of emissions costs. We note that if, in the future, Dynegy or any other affected party believes that the ISO is violating the applicable tariff provision, they may file a complaint with the Commission. We also find the provision to pay emissions costs on a pro rata basis with unpaid amounts being held over to next month is a reasonable, non-discriminatory basis to deal with unexpected shortfalls.

Dynegy's rehearing request regarding the recovery of emission costs on a pro rata basis when a generator is both providing energy under a bilateral agreement and the must-offer obligation, and the air quality district invoice is not separately invoiced, is predicated on the bilateral agreement being entered into prior to the ISO's must offer requirement. That will not always be the case, as the ISO's must offer may be required prior to a bilateral contract being entered into. Rather than monitoring when such arrangements are entered into, we believe that it is reasonable to utilize the pro rata approach, as such an approach will, on balance, produce reasonable results.

4. Mitigated Market Clearing Price

a. Calculation of Non-Reserve Deficiency MCP Based on Last Stage Emergency

Reliant contends that the Commission accepted the mitigated MCP proposal without addressing any of the specific arguments it raised concerning the compliance filing. Specifically, Reliant contends that it is unreasonable to mitigate prices on an hourly basis because the ISO measures emergency conditions throughout the course of each hour, and often makes emergency declarations that are contrary to the beginning or end of clock hours. Reliant also argues that it is unreasonable to mitigate prices on the basis of hourly average prices, since emergency declarations and compensations to sellers in the ISO market have been made on a ten-minute basis. Accordingly, Reliant requests on rehearing that the Commission require that non-reserve deficiency prices reflect the highest ten-minute price in the most recent Stage 1 emergency.

Commission Response

In the December 19 Compliance Order, the Commission accepted the ISO’s proposal to reset mitigated non-reserve deficiency MCP for periods on a full clock hour, top of the hour basis, using the average hourly price.[21] Furthermore, the Commission made clear in the June 19 Order that the ISO was to use "the highest ISO hourly MCP established during the hours when the last Stage 1 was in effect" to establish the non-reserve deficiency MCP.[22] The ISO's market structure is based on the concept of a full hour. For example, dispatch is done on an hourly basis. Accordingly, reordering the merit stack order from the top of the hour is consistent with the ISO market structure. Thus, we deny Reliant's request to modify the ISO's methodology for calculating the non-reserve deficiency MCP.

b. Provision for Setting the Mitigated Market Clearing Prices

Santa Clara requests that the Commission grant rehearing of the Compliance Order to determine that units dispatched through Out-of-Market (OOM) transactions can set the mitigated reserve deficiency MCP.[23] Santa Clara believes the Commission erred and failed to undertake reasoned decision-making in refusing to allow Santa Clara's generating units to establish the mitigated reserve deficiency MCP because sales were not made in the Imbalance Energy market. It argues that the compliance order is unduly discriminatory and violates principles of fundamental fairness by subjecting a class of entities to refunds and denying those same entities the ability to establish the refund price based on their units' costs, while allowing other entities subject to refunds to establish the mitigated reserve deficiency MCP.

The ISO requests on rehearing that the Commission affirm that real-time visibility is an essential condition to ensuring a proper MCP. The ISO believes that it is unreasonable to allow generators outside the ISO control area the right to set the mitigated price, without giving the ISO a means to verify that they can deliver energy from the designated source. The ISO states that it supports the Commission's determination that generators provide the ISO with heat rate curve, meter and interchange information to verify whether a generator's bid price is consistent with its operating level on the heat rate curve. However, the ISO claims that to deny real-time visibility would potentially invite megawatt laundering outside of the California market. The ISO contends that the Commission must provide the ISO with real-time visibility of a seller's resource because after the fact data (i.e., meter and interchange data) does not indicate whether a generator is capable of performing at its proposed bid. Accordingly, the ISO

[21] December 19 Compliance Order at 62,366.

[22] June 19 Order at 62,568.

[23] December 19 Order at 62,368.

urges the Commission to affirm that real-time visibility is an essential condition of setting the MCP in both California and West-Wide.

Commission Response

In the December 19 Compliance Order, the Commission found that units dispatched under OOM or RMR calls are not eligible to set the mitigated reserve deficiency MCP.[24] The Commission also pointed out that we have consistently held that for purposes of mitigating the California market, the ISO must institute a mechanism that emulates a competitive market. As a result, we identified units dispatched through the imbalance energy market as the marginal units and the only units that can set the mitigated reserve deficiency MCP. We reaffirm our finding in this order. We note that when OOM calls are made by the ISO, suppliers realize the ISO is in a must-buy situation and sellers have the ability through market power to increase rates to unjust and unreasonable levels. It is not the intent of the Commission to allow generators who withhold generation from the imbalance energy market to set the reserve deficiency MCP, especially when the ISO is in a must-buy situation. As a result, we find it reasonable to only permit generating units that actually bid in the market clearing price auction for imbalance energy eligible to set the mitigated reserve deficiency MCP. Therefore, we deny Santa Clara's request for rehearing of this issue.

With respect to the ISO's request, we determine that it is not necessary to require generators outside of California to provide further market visibility. As we explained in the December 19 Compliance Order, it was not the intent of the Commission to require that sellers cede control of their generating units as is required under the Participating Generators Agreement (PGA) in order to be allowed to recover marginal costs under the mitigation plan. Such a requirement would be unduly burdensome and costly to the other sellers.[25] It is highly unlikely that any generator would be willing to bear this cost, given that the mitigation plan terminates September 30, 2002. Thus, such a visibility requirement would effectively preclude most, if not all, generators outside the ISO control area from being able to set the clearing price. Therefore, we deny the ISO's request on rehearing.

c. Justification for Bids Above the Mitigated Market Clearing Prices

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[24] Id.

[25] Id.

The ISO requests that the Commission reconsider its decision to no longer require generators to justify bids above the mitigated MCP when they are not accepted. The ISO argues that the elimination is inconsistent with the Commission's intent to establish mitigated prices that are transparent to market participants. For example, the ISO states that if an unreasonable price bid is selected and the ISO subsequently determines the bid justification to be unacceptable, the only available remedy to the ISO is to require generators to accept the MCP that could have been overstated by the generators unreasonable bid. The ISO claims that, even though it submits weekly market monitoring reports summarizing bidding behavior and identifying suppliers it believes are bidding prices beyond what the ISO considers to be competitive levels to the Commission, the information does not encourage suppliers to either offer energy at competitive prices or affirmatively justify the deviation from what is considered a competitive price.

Commission Response

We will deny the ISO's request for rehearing on this issue. The December 19 Compliance Order[26] clarified that the requirement to submit cost justification for bids that are above the mitigated MCPs but are not accepted is unnecessary and not supported by the April 26 and June 19 Orders requiring cost justification.[27] These Orders require sellers to justify each transaction, not each bid, above the mitigated price. The ISO has not presented any new argument to persuade us to modify our finding. Therefore, we affirm that sellers should only be required to submit cost justification to the ISO in cases where bids above the mitigated MCPs are accepted.

With regard to the ISO's contention that the submission of weekly bid data to the Commission does not encourage sellers to offer competitive prices, we find the ISO's allegations are speculative and unsupported. In the April 26 Order, we indicated that:

> At the end of each month in which a generator submits a bid higher than the market clearing price, the generator must file with the Commission and the ISO, within seven days of the end of the month, its complete justification, including a detailed breakdown of all of its component costs for each transaction exceeding the market clearing price established by the proxy

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[26] Id. at 62,365.

[27] April 26 Order at 61,359 and the June 19 Order at 62,564.

> bid. The justification must be based on a showing of actual marginal costs higher than the market-clearing price.[28]

As a result, we continue to believe that the current reporting and monitoring requirements provide market participants with adequate assurance that rates remain just and reasonable. Accordingly, we deny the ISO's request for rehearing.

5. Creditworthiness Adder

SoCal Edison claims on rehearing that the Commission erred in its determination that sellers who bid above the mitigated price need not justify the ten percent adder. It argues that to allow sellers the ability to bid above the mitigated price and collect a ten percent surcharge will cause rates to be unjust and unreasonable. They believe that sellers that choose to bid above the mitigated price should bear the burden of showing that each element of their bid is cost-justified. SoCal Edison claims that sellers have the option to either sell to the ISO or through bilateral contracts if they believe it would be difficult to receive payment from the ISO for their power. SoCal Edison suggests that the Commission require sellers that choose to bid above the mitigated price to justify their need for a creditworthiness adder, and require the ISO to only pay the seller the amount that it bid above the mitigated price without the addition of the ten percent surcharge.

Commission Response

In the December 19 Compliance Order, the Commission accepted the ISO's proposed tariff revision reflecting the implementation of the ten percent credit risk adder, as modified by our findings in the Rehearing Order.[29] The purpose of the 10 percent adder was to compensate sellers for the potential of nonpayment in California. We explained in the Rehearing Order that the mitigated MCP should not include the 10 percent creditworthiness adder, since these prices are applicable to all spot market sales in

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[28] April 26 Order at 61,359.

[29] December 19 Compliance Order at 62,370; December 19 Rehearing Order at 62,210.

the WSCC, and the adder applies only within California.[30] We also stated that a generator whose bids above the mitigated price are accepted should not include the ten percent adder in their justification filing. Consequently, we disagree with SoCal Edison's contention that the ten percent surcharge will cause rates to be unjust and unreasonable. When sellers seek to justify each transaction above the market clearing price, the ten percent surcharge is a separate charge imposed by the ISO to compensate sellers for the risk of nonpayment in California. As a result, we do not find it necessary to require sellers to justify the costs when the intent of the surcharge was to reflect credit uncertainty in the California market. Accordingly, we deny the ISO's request for rehearing.

7. Average Heat Rate v. Incremental Heat Rate

Reliant, Dynegy and Williams request that the Commission clarify the appropriate application of filed heat rates under Section 2.5.23.3.4 of the ISO Tariff. Reliant claims that the Commission did not address their previously raised concern with regard to the ambiguous language of calculating the proxy price during reserve deficiency periods. Consequently, Reliant alleges that the ISO has used its own discretion to calculate the proxy price by adjusting filed average heat rates to create its own incremental heat rate estimates. Williams and Dynegy argue that the use of the incremental heat rate curve does not allow for the recovery of minimum load costs. Parties suggest that the most reasonable method for calculating the proxy price is the use of an average heat rate because the average heat rate is the most accurate measure of the actual cost of producing energy.

Duke requests Commission clarification that our acceptance of the ISO’s compliance filing does not foreclose continued litigation of whether average or incremental heat rates should be used to compute the marginal units fuel costs contained in the mitigated MCP (i.e., pre June 20 mitigation plan). Duke contends that the resolution of what type of heat rate should be used to compute the mitigated MCP during the refund period is a matter that should be determined in the refund proceeding currently under litigation.

Commission Response

We clarify that the use of an incremental heat rate curve is appropriate for calculating the marginal costs of each generating unit to determine the mitigated reserve

[30]December 19 Rehearing Order at 62,210.

deficiency MCP. In the June 19 Order,[31] we noted that the ISO requested heat rates for eleven different operating points with the first and last points representing the unit's minimum and maximum operating level. Additionally, our June 19 Order noted that by collecting eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each generating unit. We note that this clarification on the use of incremental heat rate curves is consistent with our finding in the April 26 Order that required heat rates to reflect operational heat rates that did not include start-up or minimum load fuel costs because, in a declared emergency, the market clearing price should reflect the cost to generate at or near maximum outputs.[32]

With respect to Williams' argument, the Commission will address the most reasonable heat rate curve methodology to recover minimum load cost in the Compliance Order being issued concurrently with this order.

We clarify for Duke that the incremental heat rate should be used to calculate the mitigated reserve deficiency MCP during the prospective period (i.e., from June 20, 2001). We note that Duke's requested clarification regarding the appropriate heat rate curve to be used in the refund period is addressed in the Rehearing to the Order on Clarification and Rehearing being issued concurrently with this order.

The Commission orders:

The requests for rehearing and clarification of the December 19 Compliance Order are hereby denied, as discussed in the body of this order.

By the Commission. Commissioner Massey dissented in part with a
separate statement attached.

(S E A L)

[31] June 19 Order at 62,563.

[32] 95 FERC ¶ 61,115 at 61,359.

Linwood A. Watson, Jr.,
Deputy Secretary.

APPENDIX

California Independent System Operator Corporation (ISO)

The City of Santa Clara, California (Santa Clara)

The City of Vernon, California (Vernon)

Cogeneration Association of California/Energy Producers & Users Coalition (CAC/EPUC)

Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (Duke)

Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (Dynegy)

Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. (Reliant)

Southern California Edison Comp

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company
Complainant,

v. Docket No. EL00-95-056

Sellers of Energy and Ancillary Services Into
Markets Operated by the California
Independent System Operator Corporation
and the California Power Exchange Corporation,
Respondents.

Investigation of Practices of the California Independent System Operator and the California Power Exchange Docket No. EL00-98-049

(Issued May 15, 2002)

MASSEY, Commissioner, dissenting in part:

This order addresses a narrow rehearing issue regarding the ten percent creditworthiness adder. I dissented from the decision to allow the creditworthiness adder in our July 25 Order [1] and in our December 19 Order. I continue to disagree with the allowance of this adder.

Therefore, I must dissent in part from today's order.

William L. Massey
Commissioner

[1] San Diego Gas & Electric Co., et al., 96 FERC ¶ 61,120 (2001) at 61,521-61,523.